Spectra Energy Transmission
5400 Westheimer Court
Houston, TX 77056

Mailing Address:
P.O. Box 1642
Houston, TX 77251-1642

Spectra Energy

March 17, 2008

Department of the Interior
Minerals Management Service
Attn: Regulations and Standards Branch
381 Elden Street, MS-4024
Herndon, VA 20170-4817

RE: Pipelines and Pipeline Rights-of-Way
RIN 1010-AD11
Minerals Management Service Notice of Proposed Rulemaking
30 CFR Part 250, 253, 254, 256

Spectra Energy Transmission, LLC ("SET") operates an extensive interstate natural gas transmission system through its subsidiary entities including Algonquin Gas Transmission, LLC, East Tennessee Natural Gas, LLC, Texas Eastern Transmission LP, Egan Hub Storage, LLC, and Maritimes & Northeast Pipeline, L.L.C.

This pipeline system receives natural gas from the major production areas of the Gulf Coast and Canada for transportation and sale primarily in the Midwest and Northeastern United States. The operation of this pipeline system, including its 560 miles of offshore pipeline in the Gulf of Mexico and off the coast of Massachusetts ("Offshore Pipelines"), is subject to the requirements of Title 49 Code of Federal Regulations Parts 190, 191, 192, 193, and 199. In addition, the Offshore Pipelines in Federal waters are subject to certain sections of 30 CFR Part 250 relating to pipeline right-of-way grants, including applications for right-of-way grants, bonds, payments, expiration of grants and abandonment.

The SET Offshore Pipelines will be affected by the NPRM which will significantly revise the Minerals Management Service ("MMS") Outer Continental Shelf pipeline and pipeline rights-of-way ("ROW") regulations and, on such DOT jurisdictional pipelines, have the unintended consequence of imposing duplicative, inconsistent, costly and unnecessary set of rules.

It is the belief of SET that this was not the intent of MMS. Thus, SET requests that MMS clarify exactly which components of the proposed rules it intends to apply to DOT pipelines and which components would apply only to non-DOT pipelines. In the event and to the extent jurisdiction is intended to be overlapping, SET also requests an explanation of any deficiencies in current operations that such regulations are intended to address.

A. INTENT OF THE PROPOSED RULEMAKING AS TO DOT PIPELINES IS NOT CLEAR

The current language in 30 CFR Part 250, Subpart J clearly specifies which sections apply to Department of Interior ("DOI") pipelines and which provisions apply to all offshore pipelines (including DOT pipelines). The clarity of the current language minimizes any potential overlap and conflicts between MMS regulations and DOT regulations. The language of the NPRM no longer clearly defines which sections of Subpart J would apply only to DOI pipelines (and therefore not apply to DOT pipelines).
Examples of current distinctions are:

- In 250.1003 the NPRM reads:

  "Which departments have jurisdiction over OCS pipelines?

  An OCS pipeline is under the jurisdiction of either the Department of Interior (DOI) or the Department of Transportation (DOT)."

- In 250.1004 the NPRM reads:

  "What are the criteria for determining jurisdiction?

  (a) DOI jurisdiction criteria. An OCS pipeline is under DOI jurisdiction if it is:
  (1) A lease term pipeline that is not subject to regulation under 49CFR, parts 192 and 195, and does not cross into State waters; or
  (2) A ROW pipeline that is operated by an identified pipeline operator (the person or entity identified by the pipeline ROW holder as authorized to control or manage the pipeline's operations), and that is either:
      (i) A producing pipeline operator (the identified pipeline operator of an ROW pipeline that is a lessee or designated lease operator of one or more OCS leases), unless it is subject to regulation under 49 CFR, parts 192 and 195, and crosses into State water or:
      (ii) A transporting pipeline operator (the identified operator of an ROW pipeline that is not a lessee or designated lease operator of an OCS lease), and the pipeline is not subject to regulation under 49 CFR, parts 192 and 195.

  (b) DOT jurisdiction criteria. An OCS pipeline that is not under DOI jurisdiction (see paragraph (a) of this section) is under DOT jurisdiction.

(c) Jurisdiction transfer. You may request that a pipeline under DOI jurisdiction be transferred to DOT jurisdiction, or that a pipeline under DOT jurisdiction be transferred to DOI jurisdiction, by submitting a written petition of approval to the Regional Supervisor and DOT Office of Pipeline Safety (OPS) Regional Director. In the petition, you must provide sufficient justification for the transfer. The Regional Supervisor and the DOT OPS Regional Director will decide jointly whether to approve the petition.

SET believes the language mentioned above is clear as to jurisdictional boundaries between DOI and DOT. Furthermore, in 1996, DOI and DOT entered into a Memorandum of Understanding (MOU) to further delineate areas of responsibility and to reduce the burden of overlapping jurisdictions and inconsistencies between agency requirements. SET understands that the 1996 MOU is still in place and has not been modified or renegotiated by DOI and DOT.

Given the clear and unambiguous language in 250.1003 and 250.1004, SET believes the subsequent language in the NPRM is intended to apply to DOI, not DOT, pipelines, unless DOT pipelines are explicitly mentioned. SET requests the MMS clarify the language specifically in 250.1006 which reads:

- "When must I submit the applications, requests, plans, and reports, and make the notifications required by this subpart?

(a) Applications and requests. For **all** OCS pipelines you must submit applications to MMS, and receive approvals, according to the following table: ....

In paragraph (a), SET believes the wording should say "all DOI OCS pipelines." This wording would be consistent with the definitions mentioned in only a few paragraphs, 250.1003 and 250.1004, earlier in the NPRM.

B. DUPLICATION AND CONFLICT WITH DOT REGULATIONS

The NPRM creates numerous conflicting and duplicative requirements between the DOT and the DOI. Consequently, SET believes the NPRM creates confusion, inconsistencies, and redundancy for the natural gas transmission offshore operators and contradicts the 1996 MOU between DOT and DOI governing their respective responsibilities on the OCS. The intention of the MOU was expressed in the Federal Register notice of February 14, 1997:

> *The MOU places, to the greatest extent practicable, producer Operated pipelines under DOI responsibility and transporter operated pipelines under DOT responsibility. Producers are companies which are engaged in the extraction and processing of hydrocarbons on the OCS. Transporters are companies which are engaged in the transportation of those hydrocarbons. As a result of this revision, some pipelines, predominantly producer operated pipelines, currently under DOT responsibility, will be*

> *under DOI responsibility......the changes described in the MOU will substantially reduce the burden of overlapping Federal jurisdictions and inconsistencies between agency requirements This will substantially increase the efficiency of governmental resources on the OCS without compromising safety.*

In addition to being duplicative, in some cases the NPRM expands processes and procedures already required by DOT. Below are some of the more significant duplicative and conflicting requirements of the NPRM.

Integrity Management Program
As required by the Pipeline Safety Improvement Act of 2002, DOT promulgated broad and comprehensive regulations for Gas Transmission Pipeline Integrity Management Programs (IMP) for High Consequence Areas (HCA's) (49 CFR 192 Subpart O). These regulations required gas transmission pipeline operators to develop and implement an integrity management program for pipelines in HCAs by December 17, 2004.

Subpart O requires an operator's IMP to include provisions for HCA identification, risk assessment, conducting baseline assessments and reassessments, remediation of conditions discovered by assessments, preventive and mitigative measures, performance measures, and reporting requirements. Any offshore areas meeting the definition of a HCA would fall under the DOT IMP. The NPRM is requiring a "written integrity management program for your OCS pipelines that includes the ... seven elements."

Unlike the DOT plan, the MMS plan is very general, vague and makes no distinction for HCAs. It appears the MMS plan is for all the pipes in the OCS, not just those in HCAs. SET believes the current DOT regulations for IMP for DOT pipelines are adequate to ensure the safety of offshore DOT pipelines and requests MMS to clarify that this requirement in the NPRM will not apply to DOT pipelines.

Emergency Plans
DOT requires operators to have emergency operating procedures in place along with requirements for conducting emergency drills, establishing communication protocols, etc. These plans have been tested and refined through emergencies, storms and hurricanes over many years. The NPRM requires "a written emergency plan that you will immediately implement in the event of a pipeline failure, accident, or other emergency ...." SET believes the current emergency plans required by DOT regulations are adequate for offshore DOT pipelines and requests MMS to clarify that this requirement in the NPRM will not apply to DOT pipelines.

Personal qualification programs
DOT regulations require pipeline operators to develop written qualification programs to evaluate the ability of employees and contractors to perform "covered tasks" and to recognize and respond to Abnormal Operating Conditions (AOCs) that may be encountered while performing these activities. The operator qualification program includes offshore employees performing covered

tasks. The NPRM requires "a written qualification program for individuals who perform pipeline operation, maintenance, and repair duties that may affect the safe operation or integrity of the pipeline." SET believes the current DOT operator qualification program is adequate for safe and reliable operation of offshore DOT pipelines and requests MMS to clarify that this requirement in the NPRM will not apply to offshore DOT pipelines.

Operations and Maintenance Manual (O&M)

DOT requires natural gas transmission pipeline operators to develop and maintain an O&M Manual. DOT routinely performs audits of an operator's O&M Manual to ensure it meets the requirements of DOT regulations. Additionally, PHMSA inspects the operator to ensure it is complying with its O&M Manual. The NPRM requires "you must operate and maintain a pipeline manual that" addresses five specific areas. SET believe there is no safety benefit to requiring a duplicative O&M manual, and requests MMS to clarify that this requirement in the NPRM will not apply to offshore DOT pipelines.

Reburial of Pipe

DOT requires burying pipelines in shallow water (12 feet or less) except in the Gulf of Mexico where pipelines must be buried in water depths less than 200 feet. DOT also requires gas pipeline operators to periodically inspect their pipelines in the Gulf of Mexico in water depths up to 15 feet and rebury pipelines found to be exposed or a hazard to navigation. The NPRM would require burial of pipe in water less than 200'. Additionally, it requires that the pipeline remain buried at its approved burial depth throughout the life of the pipeline. SET believes the current DOT regulations regarding pipeline cover and inspection are adequate to address any significant pipeline safety issues, and the provision in the NPRM is not warranted. SET requests MMS to clarify that this requirement in the NPRM will not apply to offshore DOT pipelines.

Pipeline Patrol

DOT requires offshore pipelines to be patrolled at least annually. The NPRM requires "you must conduct a visual survey of each of your pipeline routes at least monthly (or at a frequency specified by the Regional Supervisor) for an indication of leaks." The NPRM frequency for leak patrol is significantly greater than the DOT onshore standard for routine patrols and much greater than the annual leak survey requirement. SET believes the current DOT requirement for patrolling is adequate to ensure pipeline safety, and requests MMS to clarify that this requirement in the NPRM will not apply to offshore DOT pipelines.

Pipeline Safety Equipment

DOT regulations largely focus on safety to the public, employees and the environment, something the gas transmission industry also considers its highest priority. The NPRM introduces a number of new safety equipment requirements. This includes some strict requirements such as one requiring operators to shut in the pipeline immediately should safety equipment not operate as intended. It also sets out certain notifications – out-of-service and correction action – along with a repair application procedure. SET does not believe requiring repair plans to be submitted to MMS for approval prior to initiating repairs provides a benefit to pipeline safety. We believe this will simply cause needless delays in returning offshore facilities to service, potentially impacting the nation's energy supply.

Summary

SET believes that the NPRM creates numerous conflicting and duplicative requirements between the DOT and the DOI. This creates confusion for pipeline operators, and will result in inefficient use of an operator's resources. In addition the MMS' proposed regulations, unless clarified, are inconsistent with the DOT regulations and will create jurisdictional overlaps. The NPRM also contradicts the 1996 MOU between DOT and DOI. SET believes conflicting and duplicative requirements do not add to pipeline safety, and requests MMS to clarify that these requirements do not apply to offshore DOT pipelines.

C. THE PROPOSED RULEMAKING CONTRADICTS THE MOU WITH DOT

SET believes the NPRM, as currently written, contradicts the 1996 MOU between DOI and DOT. A review of the MOU, statutes and regulations leads to the conclusion that DOI and DOT have Federal authority over pipeline safety of their respective designated facilities. The 1996 MOU between DOT and DOI clearly recognizes this fact, such that the potential of overlapping or conflicting regulations of OPS and MMS is the underlying reason for establishing the MOU. There is no indication that the agreements made in the MOU have been abrogated as provided for in the language of the MOU.

The NPRM purports to re-write 30 CFR Part 250 which is directed at pipelines offshore. In the process it has retained parts of its previous rules and added many new ones, some of which were contained in non-rulemaking form such as Notice to Lessee (NTL). MMS is also proposing changes to 30 CFR Part 253, Oil Spill Responsibility, Part 254, Oil Spill Response Requirements and Part 256, Leasing of Sulphur or Oil and Gas. The authority for these regulations is based upon the OPA, the OCSLA and the FWPCA.

In 1996, DOT and DOI entered into a revised MOU to replace the pre-existing May 6, 1976 MOU governing their respective responsibilities on the OCS. The intention was expressed in the Federal Register notice of February 14, 1997:

> *The MOU places, to the greatest extent practicable, producer operated pipelines under DOI responsibility and transporter operated pipelines under DOT responsibility. Producers are companies which are engaged in the extraction and processing of hydrocarbons on the OCS. Transporters are companies which are engaged in the transportation of those hydrocarbons. As a result of this revision, some pipelines, predominantly producer operated pipelines, currently under DOT responsibility, will be under DOI responsibility......the changes described in the MOU will substantially reduce the burden of overlapping Federal jurisdictions and inconsistencies between agency*

> *requirements This will substantially increase the efficiency of governmental resources on the OCS without compromising safety.* ***(62 Fed Reg. No. 31 February 14, 1997)***

Analysis of MOU Flexibility

The 2007 NPRM includes the following statement about the 1996 MOU signed between DOI and DOT:

> *The MOU includes the flexibility to cover situations that do not correspond to its general definition of the jurisdictional boundary as "the point at which operating responsibility transfers from a producing operator to a transporting operator." The MOU also provides that DOI and DOT may, through their enforcement agencies and in consultation with the affected parties, agree to exceptions to the MOU on a facility-by-facility or area-by-area basis. Operators may also petition DOI and DOT for exceptions to the MOU.*
>
> *(72 Fed Reg. No 191, Oct 3, 2003 AT 56443)*

The above statement seems to assert that there is flexibility in the MOU that allows MMS to apply new regulations or interpretations to DOT jurisdictional facilities in certain situations. To rely on such "flexibility" for the wholesale imposition of MMS regulation on DOT pipelines as proposed in the NPRM is a gross misuse of the intended flexibility and implied MMS authority. Throughout the preambles of the Federal Register Notices that implemented the MOU, the MMS regulations implementing provisions of the MOU, and the DOT regulations implementing provisions of the MOU, there are explanations of the specific types of exceptions the MOU is referring to as to the intent. Below are examples:

> *For those instances in which adjoining operators do not or can not agree on a transfer point, RSPA's Office of Pipeline Safety (OPS) and MMS will make a joint determination of the boundary).*
> *(62 Fed Reg. 61692, Nov. 19, 1997)*
> *Pipeline Safety: Producer-Operated Outer Continental Shelf Natural Gas and Hazardous Liquid Pipelines That Cross Directly Into State Waters:*
> *By exempting the producer-operated pipelines from RSPA/OPS regulation, this rule will reduce overlapping regulation in accordance with the MOU of December 10, 1996*
> *(68 Fed Reg., 46109, July 29, 2003)*

MMS' misinterpretation of the flexibility in the MOU results in the MOU having the opposite meaning of its intended purpose as demonstrated by the new proposed regulations. If an exception to the MOU is interpreted to make the MOU substantially nebulous or ambiguous, then the MOU would become meaningless and could be undermined by exceptions that were never intended, thereby making such an exception illogical and infeasible. Exceptions of the magnitude in the new proposed regulations would have obviously been specifically mentioned in the MOU.

D. THE PROPOSED RULEMAKING CONFLICTS WITH THE JURISDICTION OF THE FERC

The proposed rules would inappropriately conflict with the authority and jurisdiction of the Federal Energy Regulatory Commission and the Natural Gas Act, in violation of 43 USC 1334 (f)(4). By attempting to create in itself authority to declare forfeit and expire a pipeline right of way grant supporting a pipeline subject to the Natural Gas Act and the Federal Energy Regulatory Commission, MMS would in effect negate the abandonment authority under the Natural Gas Act that is the exclusive province of FERC.

The new rules create, for the first time, the threat that a pipeline right of way grant may be terminated, at the sole discretion of MMS, because of a temporary interruption of gas flow. This contravenes the due process protections found in 43 USC 1334 (e).

To the extent the new rules threaten the continuing viability of existing right of way grants because of a temporary cessation of gas flow, they are inconsistent with the Congressional declaration of policy [see 43 USC 1332 (3)] favoring expeditious and orderly development of energy resources in the outer continental shelf. It is axiomatic that the needless elimination of necessary transportation options would negatively impact the development of natural resources.

Aside from the jurisdictional conflict with FERC, the new rules would impose an illogical and environmentally damaging requirement to use new rights of way rather than allow the reuse of existing rights of way. To the extent the rules contemplate the termination of rights of way grants and the decommissioning of pipelines that retain economic and developmental utility, the new rules have the effect of requiring new pipelines to be installed in new rights of way grants even though they were just replacing pipelines which MMS' regulations require be taken out of service.

E. COST – BENEFIT EVALUATION

The NPRM asserts that the proposed rule is not a significant rule as determined by OMB and is not subject to review under EO 12866. SET disagrees with this assertion. The MMS cost estimate only includes reporting, record keeping and fees. SET believes the MMS must also include the cost of implementing the requirements of the NPRM, such as performing integrity assessments, pipeline reburial, additional patrolling, etc. If the cost of implementing the NPRM is included in the cost analysis, SET believe the proposed rule will have an annual effect well in excess of $100 million or more to the economy, and thus a cost/benefit analysis must be performed.

Cost Analysis

SET participated in an Interstate Natural Gas Association of America ("INGAA") effort to develop preliminary estimated costs to implement the rule. The INGAA estimates show a potential annual compliance of approximately $1.04 billion per year over the next ten years and a one time cost of $162 million to develop the required program, plans and procedures.

The information discussed in this section is based on a review of the MMS cost analysis and input from several INGAA member companies. The cost information provided by MMS does not agree with company experience and expectations for the identified activities. SET believes the hours were significantly underestimated as was the per hour cost. In addition, the MMS analysis of costs only addressed expected administrative burden and did not address the costs to actually perform the identified activities such as patrolling, burying pipelines, and integrity assessments. SET believes the preliminary cost estimates prepared by INGAA accurately reflect the true cost of implementing the requirements of the NPRM.

Reporting
INGAA estimates the total hour burden to develop systems, reports and records, perform quality control, and obtain management approval and legal review to be 117,600 hours with an associated cost of **$8,820,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 20 hours for general departure and compliance requests
- 500 hours to retain all records and make available to MMS
- 400 hours to generate a petition to change jurisdiction
- 20 hours to mark DOI/DOT interface and note of records

Forms
INGAA estimates the total hour burden to complete forms, perform quality control, and obtain management approval and legal review to be 38,900 with an associated cost of **$2,917,000.** This cost is based on an average hours as shown below with a $75/hour rate:

- 20 hours for each notice under 1041(c), 1058(b) and 1093(f)
- 10 hours for completion and submission of form MMS-2030
- 120 hours to submit form MMS-2030
- 120 hours to submit form MMS-149

Applications for New Pipelines
INGAA estimates the total hour burden to develop applications, perform quality control, and obtain management approval and legal review to be 423,000 hours with an associated cost of **$31,725,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 800 hours to prepare and submit applications
- 20 hours impacted lessees
- 300 hours to submit third party review

Pipeline Design and Construction
INGAA estimates the total hour burden to develop agreements and notifications, perform quality control, and obtain management approval and legal review to be 49,600 hours with an associated cost of **$3,712,500**. This cost is based on average hours as shown below with a $75/ hour rate:

- 20 hours to prepare notifications to military
- 40 hours for buoy hazards
- 100 hours to enter into agreements with command headquarters
- 120 hours to submit construction reports

Pipeline Risers Connected to Floating Platforms
INGAA estimates the total hour burden to develop, perform quality control, and obtain management approval and legal review to be 52,800 hours with an associated cost of **$3,960,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 240 hours to develop and submit riser verification plans
- 240 hours to submit final reports on design and construction

Pipeline Testing, Safety, Leak Detection, Operations and Maintenance
INGAA estimates the total hour burden to develop the required programs and plans, perform quality control, and obtain management approval and legal review to be 2,162,800 hours with an associated cost of **$162,200,000**. This is a one time cost and is based on average hours with a $75/ hour rate:

In addition INGAA estimates that the ongoing annual cost associated with these sections of the regulations is based on an hour burden of 404,000 with an associated cost of **$30,300,000** for the ongoing administrative burden to carry out the tasks and document.

Not mentioned by MMS is the cost to maintain cover to the amounts specified in proposed section 250.1078. The cost to rebury pipeline is estimated at $50,000 per mile. Based on an estimated re-burial need every ten years and considering the amount of pipe in the OCS, the annual cost is estimated at **$165,000,000**.

Not mentioned by MMS is the cost to perform the required activities that will be required once the Pipeline Integrity Program is developed. INGAA estimates that there will be a **$700,000,000** annual cost over a ten year period to make the pipeline piggable, to conduct pigging with In-line inspection devices and perform prevention and mitigation tasks as may be necessary. This cost is based on actual costs that operators have encountered implementing pipeline integrity programs for DOT. The costs for the integrity management program include modification of facilities to accommodate smart pigs, and performing the pigging operations.

INGAA estimates that several hundred new valve platforms will need to be installed to provide for pigging operations. The cost for such a platform is estimated at $10,000,000 and includes the platform, launchers, receivers, necessary valves and controls. The costs of platforms are part of the overall costs shown above.

Pipeline Modifications and Repairs

INGAA estimates the total hour burden to develop applications and notifications, perform quality control, and obtain management approval and legal review to be 70,000 hours with an associated cost of **$5,250,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 120 hours to submit application for modification
- 40 hours to submit modification report, application to repair and repair report
- 240 hours to analyze pipeline failures

Pipeline Surveying, Monitoring and Inspection

MMS did not account for the cost of equipment such as boats, barges and aircraft to perform the surveys and inspections. This type of work is difficult to estimate based on hours and therefore, INGAA estimated the costs based on typical service charges. For example the cost to patrol using aircraft is approximately $100 per mile. Performing the survey 24 times per year for 33,000 mile of pipe equates to a cost of **$59,400,000** per year.

Inspection of the various portions of pipeline risers involves vessels, equipment and personnel. The costs associated with the activities include vessel rental, diving and other equipment rental, diver and other personnel costs and involve many hours of transit time to and from the platforms. Based on a daily cost and the number of platforms involved, the cost for these inspections is estimated at **$15,200,000** per year

Pipeline Decommissioning

INGAA estimates the total hour burden to develop decommissioning plans and applications, perform quality control, and obtain management approval and legal review to be 39,600 hours with an associated cost of **$2,970,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 80 hours to submit application
- 40 hours to submit decommissioning report
- 120 hours to submit application to re-commission
- 120 hours to submit re-activation report

The costs to purge, flush and fill pipelines and maintain associated records are not fully explained in the MMS cost estimate. The costs to develop a decommissioning plan, purge the pipeline, flush the pipeline, dispose of the flushing material, filling the pipeline, and isolating from sources of product is estimated to be approximately $120,000. The total costs based on 300 events are estimated at **$36,000,000** per year.

Pipeline ROW Grants

INGAA estimates the total hour burden to develop applications and submissions, perform quality control, obtain management approval and legal review to be 45,920 hours with an associated cost of **$3,444,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 240 hours to submit the application
- 120 hours to submit arguments
- 40 hours to survey the pipeline
- 120 hours to submit application to modify grants and relinquish grants

Accessories to ROW Pipelines
INGAA estimates the total hour burden to develop applications and notifications, perform quality control, and obtain management approval and legal review to be 36,900 hours with an associated cost of **$2,767,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 240 hours to submit application
- 240 hours to submit annual report
- 2,920 hours to inspect accessories for pollution

30 CFR, Part 256
INGAA estimates the total hour burden to develop reports, perform quality control, and obtain management approval and legal review to be 30,000 hours with an associated cost of **$2,250,000**. This cost is based on average hours as shown below with a $75/ hour rate:

- 20 hours to develop and submit report

Benefit Analysis

The MMS has not provided any information in the NPRM that states the benefit of the new regulations. For the years 2006 and 2007, as reported to DOT for OCS pipeline incidents there was approximately $600 thousand of gas loss per year, $11.3 million of company costs to affect repairs per year and no cost to the public. This is for the approximately 14,000 miles of DOT jurisdictional pipe. The costs for 2005 were significantly higher due to two major hurricanes in the Gulf of Mexico. The gas loss cost that year was $11.4 million with the company costs of repairs being $74.6 million and no costs to the public. A four year average (2004 to 2007) shows an average per year gas loss cost of $4.3 million, an average per year for company repair and any clean up cost of $29.5 million with no costs to the public. During this period there were no fatalities or injuries reported to DOT.

A reduction of incidents and related costs may be achieved through the implementation of some of the proposed programs such as an integrity management program. If incidents could be reduced by 20 % (two-thirds of the corrosion related incidents), this would relate to an estimated cost savings of approximately $2.4 million (20% of $11.9 million, 2006 and 2007 average gas loss and company repair costs).

Information on reportable incidents submitted to DOT shows the following as causes:

- 31% due to internal corrosion with most of these being small pits
- 27% due to heavy rains and floods with most of these during the 2005 hurricanes
- 11% were categorized as miscellaneous or unknown
- 9% due to damage by aquatic vehicle

- 6% were component failures
- 16% due to several other causes

Information on the annual leak report information submitted to DOT shows the following causes:

- 40% due to corrosion with most of these being small internal corrosion pits
- 27% due to natural forces with most of these during the 2005 hurricanes
- 11% due to excavation damage
- 9% due to materials and welds
- 13% due to several other causes

INGAA has reviewed the information on incidents and leaks reported to DOT. Incidents are reported in writing within 30 days of the incident. Leak information is reported annually.

Over the time period 2004 to 2007 which includes the hurricanes of 2005, there were no fatalities reported, nor were there any injuries reported. The incidents were reported to DOT were all reported because of the cost threshold of $50,000.

The average cost of gas lost for this time period was $4.3 million per year. The average cost to repair facilities due to incidents was $29.5 million per year. The average for two years, 2006 and 2007 (exclude 2005 when two major hurricanes cause damage), were $600 thousand per year for gas lost and $11.3 million per year for company cost to affect repairs.

Implementation of the NPRM may have a small impact on the number and related costs of incidents. Even if the incidents could be reduced by 20% (two-thirds of the corrosion related incidents), this relates to an estimated benefit of $2.4 million per year.

Summary

Based on the INGAA estimates, SET believes the following to be the true costs and benefits of the NPRM:

- The total estimated annual costs to perform the annual administration and record requirements of the NPRM to be **$68 million**.
- The total estimated one time cost to develop programs, plans, procedures, etc. based on the requirements of the NPRM to be **$162 million**.
- The total estimated annual cost of the administration, operations, maintenance, etc. requirements of the NPRM not counting the costs for integrity assessments to be **$276 million**.
- The total annual estimated cost for performing integrity assessments which includes modifications of pipeline facilities to be **$700** million per year over ten years or a total cost of $7 billion.
- An estimated annual cost benefit **$2.4** million

- There were no fatalities or injuries during the analysis years.

A cost benefit can be determined based on these numbers with the cost exceeding the benefit by a factor of approximately 433 ($1.04 billion divided by $2.4 million).

F. RECOMMENDED CHANGES TO PROPOSED REGULATIONS

Generally the clearest description of jurisdiction should be set forth in the opening section (s) of a new rule, i.e., an Applicability or a Scope Section which is the format in DOT's Parts 190-199. SET has reviewed the proposed rule and recommends that the language be amended to specify which pipelines (DOT or DOI) are covered by each of the proposed rules.

As discussed above, SET believes MMS should identify which rules do not apply to DOT pipelines. This can be done by adding language where appropriate that reflects the exclusion of DOT pipelines from certain requirements. Accordingly, SET request that MMS exclude the following categories from applying to DOT pipelines:

Pipeline Design:
250.1031 What are the general requirements for designing a pipeline?
250.1032 What must I do to avoid or mitigate hazards?
250.1033 What are the design requirements for horizontal components and risers?
250.1034 What are the design requirements for appurtenances?
250.1035 What are the design requirements for sewer service?
250.1036 When must I sectionalize a pipeline?

Pipeline Fabrication (250.1038)
Pipeline Construction (250.1040-1051)
Pipeline Pressure Testing (250.1057-61)
Pipeline Leak Detection (250.1071)
Pipeline Internal Corrosion & Flow Assurance (250.1074-1075)
Pipeline Safety Equipment (250.1062-1069)
Pipeline Operations and Maintenance (250.1078-1091)
Pipeline Modification and Repair (250.1093-97)
Pipeline Survey, monitoring, and inspecting a pipeline (250-100-1103)

In order to accomplish this result, SET suggests the consideration of a new section or subparagraph in section 250.1004 that lists the above groups and sections as excluded from requirements for DOT pipelines. That section would then read something like this:

Sec. 250.1004 What are the criteria for determining jurisdiction?

(a) DOI jurisdiction criteria. An OCS pipeline is under DOI jurisdiction if it is:

(1) A lease term pipeline that is not subject to regulation under 49 CFR, parts 192 and 195, and does not cross into State waters; or

(2) An ROW pipeline that is operated by an identified pipeline operator (the person or entity identified by the pipeline ROW holder as authorized to control or manage the pipeline's operations), and that is either:

(i) A producing pipeline operator (the identified pipeline operator of an ROW pipeline that is a lessee or designated lease operator of one or more OCS leases), unless it is subject to regulation under 49 CFR, parts 192 and 195, and crosses into State waters; or

(ii) A transporting pipeline operator (the identified pipeline operator of an ROW pipeline that is not a lessee or a designated lease operator of an OCS lease), and the pipeline is not subject to regulation under 49 CFR, parts 192 and 195.

(b) DOT jurisdiction criteria. An OCS pipeline that is not under DOI jurisdiction (see paragraph (a) of this section) is under DOT jurisdiction.

(c) Jurisdiction transfer. You may request that a pipeline under DOI jurisdiction be transferred to DOT jurisdiction, or that a pipeline under DOT jurisdiction be transferred to DOI jurisdiction, by submitting a written petition for approval to the Regional Supervisor and the DOT Office of Pipeline Safety (OPS) Regional Director. In the petition, you must provide sufficient justification for the transfer. The Regional Supervisor and the DOT OPS Regional Director will decide jointly whether to approve the petition.

(new sub paragraph)
(d)
The following regulations do not apply to natural gas pipelines regulated by the DOT under 49 CFR Part 192:

Pipeline Design:
Pipeline Fabrication (250.1038)
Pipeline Construction (250.1040-1051)
Pipeline Pressure Testing (250.1057-61)
Pipeline Safety Equipment (250.1062-1069)
Pipeline Leak Detection (250.1071)
Pipeline Internal Corrosion & Flow Assurance (250.1074-1075)
Pipeline Operations and Maintenance (250.1078-1091)
Pipeline Modification and Repair (250.1093-97)
Pipeline Survey, monitoring, and inspecting a pipeline (250-1100-1103)

G. SUMMARY OF COMMENTS

SET believes the new regulations are not needed for DOT jurisdictional pipelines such as SET's Offshore Pipelines because safety requirements are adequately covered by DOT regulations. The administrative and capital costs burdens would be significant. SET urges MMS to avoid unintended consequences of the proposed rule by clarifying that it is not applicable to DOT pipelines. This oversight needs to be corrected in the final rule.

SET thanks MMS for consideration of its comments and applauds the MMS for its continued commitment to pipeline safety. SET hopes that these comments assist MMS in promulgating a clear and practicable regulation. If you have any questions or require any additional information, please contact Rick Kivela at 713-627-6388.

Sincerely,

Randall G. Schorre

Randall G. Schorre
General Manager, Transmission Services
Spectra Energy Transmission